BEFORE THE

PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF THE	)	
APPLICATION OF CHESAPEAKE	)	
UTILITIES CORPORATION FOR	)	PSC DOCKET NO. 17-1224
APPROVAL OF NATURAL GAS	)	
EXPANSION SERVICE OFFERINGS	)	

DIRECT TESTIMONY

OF

DWIGHT D. ETHERIDGE

ON BEHALF OF THE

DELAWARE PUBLIC SERVICE COMMISSION

PUBLIC VERSION

MAY 2, 2018

EXETER

ASSOCIATES, INC.
10480 Little Patuxent Parkway
Suite 300
Columbia, Maryland 21044

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Dwight D. Etheridge. I am a Principal and Vice President with Exeter Associates, Inc. ("Exeter"), an economics consulting firm specializing in the economics of regulated industry. My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I hold a Bachelor of Science degree in Business Administration from the University of California, Berkeley. I have 32 years of experience in the public utility industry. My work has been focused on business plan development, industry restructuring, rate design, class cost-of-service studies, load forecasting, resource planning, transmission system evaluations, power procurement, utility benchmarking studies, distributed generation, telecommunications, and contract negotiations. From 1986 until 1999 I worked in progressively more responsible positions at Nevada Power Company, eventually reporting to the chief executive officer while leading a team of experts assigned to industry restructuring issues. After the merger of Sierra Pacific Resources and Nevada Power Company in 1999, I worked on a variety of strategic and diverse projects related to industry restructuring, mergers, telecommunications, and resource planning.

In 2004 I became an independent consultant and worked with clients on rate design, strategic planning, competitive market analyses, and industry restructuring projects. In 2006 I joined Exeter as a Senior Analyst and in 2008 I became a Principal and Vice President in the firm. My recent consulting work with Exeter has focused on a variety of projects related to wholesale commodity energy markets, options studies for federal facilities served at transmission voltage, review of retail service arrangements, utility benchmarking studies, and regulated ratemaking.

I have provided expert testimony on 37 occasions before the Illinois Commerce Commission, Indiana Utility Regulatory Commission, Maryland Public Service Commission, Missouri Public Service Commission, Public Service Commission of Wyoming, Public Utilities Commission of Nevada, Public Utility Commission of Texas, and the Nevada Legislature on a variety of topics including: load forecasting, class cost-of-service studies and rate design, industry restructuring, hedging, transmission system evaluations, utility benchmarking studies, and various revenue requirement issues.

A summary of my qualifications is included as an appendix to this testimony.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. Exeter was retained by the Staff of the Delaware Public Service Commission ("Staff") to evaluate the application of Chesapeake Utilities Corporation ("CUC" or the "Company") for approval to offer its previously approved "Expansion Area" rates applicable only to its southeastern Sussex County Expansion Area to additional customers throughout its service territory, if elected by customers and where it is not otherwise economical for Chesapeake to provide service at its existing non-Expansion Area rates ("Application").

Q. WHAT DATA SOURCES DID YOU UTILIZE IN PERFORMING YOUR REVIEW AND ANALYSIS OF THE COMPANY'S APPLICATION?

A. I reviewed the Application, responses to interrogatories, information obtained from previous Company proceedings before this Commission, and publicly available information on the Company's financial performance and over-arching business strategies.

II. SUMMARY AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Delaware Public Service Commission ("PSC" or "Commission") approved the Company's Infrastructure Expansion Service ("IES") rates applicable to its southeastern Sussex County Expansion Area in Order 8479 entered in PSC Docket No. 12-292. Those IES Rates represented an incremental increase in the Company's otherwise applicable monthly customer charges for each of its various rate classes and were designed to make it more economical for the Company to extend natural gas service to prospective customers in the Expansion Area. For example, the Company's monthly customer charge applicable to residential customers receiving service under its RS-2 rate schedule is $13, and the IES rates increased that charge by $225 annually, or $18.75 monthly, to $31.75

per month for residential customers in the Expansion Area receiving service under the Company's ERS-2 rate schedule.[1] Incremental annual revenues of $225 would allow the Company to economically invest multiple times that amount in incremental capital investments to serve a prospective ERS-2 customer, thereby facilitating the expansion of natural gas service in its service territory. Expanding the availability of natural gas service in the Expansion Area serves the public good by providing residents and businesses of southeastern Sussex County with an alternative form of energy that they could choose to utilize if they agreed to receive natural gas service at the Company's rates for that area that included the IES rates.

Based upon my review of the Company's Expansion Area program, I would consider the program to be a success both from a public policy perspective—more customers have access to natural gas service, and from the prospective of the Company's shareholders—the Company is leveraging the program to "grow" its rate base and, in turn, corporate earnings per share. From the perspective of existing customers, the program has probably not been either detrimental or necessarily beneficial, yet.

When the program was initiated by the Commission on December 1, 2013 following PSC Docket No. 12-292, there was a provision adopted with the program to protect existing customers from upward pressure on the Company's revenue requirement in a base rate proceeding related to the financial performance of the Company's aggregated portfolio of expansion projects. That protection has since expired. Given the overall strategic value of the Expansion Area program to the Company, and the added strategic value it would gain with its proposal to expand the availability of IES rates to expansion projects throughout its service territory, it would be proper for the Commission

[1] Rate Schedule "RS-2" is applicable to residential customers with annual consumption of 240 Ccf, which is a majority of the Company's residential customers. "Ccf" equals the volume of 100 cubic feet of natural gas.

to again approve risk mitigation measures for existing customers and, in fact, enhanced mitigation measures given both the financial success of the program for the Company's shareholders and because the use of IES rates is expected to expand.

With its Application, the Company is seeking to utilize its Commission-approved IES rates outside of the Expansion Area and within its existing service territory for prospective customers located relatively close geographically to existing customers receiving service under the Company's non-IES rates. That introduces certain public policy concerns from a ratemaking perspective because residents in neighboring communities will be paying different monthly customer charges, which could lead to both customer confusion and dissatisfaction with the ratemaking policy overseen by the Commission. Businesses too will be paying different monthly customer charges if the Company expands service to them using IES rates as the Company proposes, thereby introducing additional concerns from a ratemaking perspective where competing business could be charged different rates. For those reasons, it would be important for the Commission from a public policy perspective to chart a course forward toward equalizing the customer charges for IES and non-IES customers over time. This issue should be discussed in this case with the goal being to implement a path forward sooner rather than later.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSAL TO OFFER IES RATES THROUGHOUT ITS SERVICE TERRITORY?

A. The Commission should not approve the Company's request without risk mitigation measures that Staff is proposing to protect existing customers against upward pressure on the Company's revenue requirement in a base rate proceeding that could be caused by the

Company's expansion projects, whether undertaken in the Expansion Area or throughout its service territory using the IES rates as the Company is proposing in its Application. The risk mitigation measures that Staff is proposing provide protection against:

- Individual expansion projects that fall more than 15 percent below the Company's customer projections and with either: (1) capital investments in approach mains equal to or greater than $500,000, or (2) actual buildouts that exceed 36 months.
- A situation where the Company's rate of return on rate base for its aggregated portfolio of expansion projects falls below the authorized rate of return determined in that proceeding, plus 50 basis points, and where the aggregated portfolio of expansion projects includes projects undertaken since December 1, 2013, but not to exceed the ten years ending with the end of the test period in the base rate proceeding.

With those risk mitigation measures, Staff supports approval of the Company's request in its Application to apply IES rates throughout its service territory where it would otherwise not be economical for it to extend service at its existing non-Expansion Area rates.

In addition, charting a course toward equalized customer charges for IES and non-IES rate customers is an important public policy issue that warrants discussion in this proceeding and the selection of a path forward sooner rather than later.

III. SOUTHEASTERN SUSSEX COUNTY EXPANSION AREA RESULTS

Q. WHEN DID THE COMMISSION ADOPT THE IES RATES FOR THE SOUTHEASTERN SUSSEX COUNTY EXPANSION AREA?

A. The Commission's Order 8479 entered in PSC Docket No. 12-292 was filed on November 6, 2013 and specified that "the proposed rates set forth in the approved Settlement Agreement shall be effective for bills rendered on or after December 1, 2013."[2] The referenced settlement agreement had been filed with the Commission on October 1, 2013.

Q. WHEN DID THE COMPANY BEGIN UTILIZING THE COMMISSION-APPROVED IES RATES TO PROMOTE THE EXPANSION OF NATURAL GAS SERVICE IN THE EXPANSION AREA?

A. The Company first utilized the IES rates to evaluate the economics of extending natural gas service to the planned Senators residential housing development located on Gills Neck Road in Lewes, Delaware, in the October 2013 timeframe, or shortly after the settlement agreement was filed in PSC Docket 12-292 but before the first homes had been constructed. Using its confidential Internal Rate of Return Model ("IRRM"), the Company determined that it would be economical to extend natural gas service to that planned development using the IES rates.

Q. PLEASE SUMMARIZE THE COMPANY'S IRRM.

A. The Company's IRRM is a relatively straightforward financial model that utilizes inputs on capital costs to represent cash outflows and natural gas delivery service revenues to represent cash inflows, with various other inputs and calculations to accurately model projected cash flows over the life of the project. Other inputs include the Company's cost of capital and projections of its operations and maintenance ("O&M"), interest, book depreciation, and tax depreciation expenses. The Company's IRRM is a long-term model in that it extends well into the future, e.g., more than 50 years, to model the cash flows

[2] PSC Docket No. 12-292, *Order 8479*, p. 8 (November 6, 2013).

for the entire depreciable life of the capital investments that the Company is projecting are necessary for a project. Projected net cash flows are used to calculate the internal rate of return on a project that is compared to the threshold return on equity utilized by the Company in its IRRM to determine if it is economical to extend natural gas service to an expansion project. Projects with an internal rate of return at or above that threshold return on equity would be expected to produce an earned return on equity at or above the threshold over the life of the project, thereby indicating that it would be economical for the Company to proceed with the project.

The Company's IRRM also has a threshold rate of return on rate base. However, because the cost of capital inputs in the model are fixed for any given project evaluation, achieving the return on equity threshold assures that the rate of return on rate base threshold will also be achieved, and vice versa, thereby rendering a project economic. I focus on the return on equity threshold because the internal rate of return calculation in the IRRM produces a return on equity, not a rate of return on rate base.

Q. WHAT WOULD HAPPEN IF A PROJECT DID NOT PRODUCE AN INTERNAL RATE OF RETURN AT OR ABOVE THE THRESHOLD RETURN ON EQUITY IN THE COMPANY'S IRRM?

A. The Company would require an upfront payment typically referred to as a contribution in aid of construction ("CIAC") from either a project's developer or individual customers within the project to make up any shortfall in the project's expected internal rate of return. A CIAC would serve to reduce the Company's upfront capital cost outlays, i.e., it would serve to lower initial cash outflows, thereby improving the internal rate of return for the project. In the case of the Senators project, no CIAC was needed.

Q. WOULD THE SENATORS PROJECT HAVE REQUIRED A CIAC IF THE COMPANY WAS NOT ABLE TO UTILIZE THE IES RATES?

A. Yes. With the Company's non-IES rates, the Company estimated that the Senators project would have required a CIAC of $124,864, or $675 per customer for the 185 customers that the Company was projecting for the buildout.[3]

Q. PLEASE DESCRIBE GENERALLY OTHER RESIDENTIAL DEVELOPMENT PROJECTS THAT THE COMPANY HAS SINCE BEEN ABLE TO EXTEND NATURAL GAS SERVICE TO USING THE IES RATES.

A. Since it undertook the Senators project in 2013 and through 2016, the Company has extended or is moving forward with extending approach and development mains to provide natural gas service to 17 additional residential development projects each with at least 24 projected customers.[4] Fourteen of those projects have been in and around Lewes, Delaware, with the remaining three located east of Selbyville, Delaware. Like the Senators project, each of those 17 additional projects met or exceeded the Company's return on equity threshold in its IRRM with the IES rates [redacted]. Including the Senators project, the Company projected a combined total of [redacted] incremental residential customers that would receive natural gas service in those projects. That represents a sizable number of residential customers when compared with, for example, the Company's reported 41,466 average number of residential customers in 2014.[5] Having extended its approach mains to those projects, the Company was also able to extend natural gas service to additional residential customers in certain locations either

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[3] *See* Company's response to Staff interrogatory PSC-3.c.

[4] "Approach" mains are extensions of the Company's distribution system to developments, and "development" mains are extensions within a development from which service piping can be installed to serve customers.

[5] *See* PSC Docket No. 15-734, *Direct Testimony C. James Moore*, p.8 (December 21, 2015).

directly from the approach mains, i.e., "on-main" customers, or via a development main extension.[6]

Q. YOU STATED THAT THE 18 PROJECTS INCLUDING THE SENATORS PROJECT EACH MET OR EXCEEDED THE COMPANY'S RETURN ON EQUITY THRESHOLD IN ITS IRRM USING THE IES RATES [redacted]. WHAT ARE THE FINANCIAL IMPLICATIONS TO THE COMPANY FOR PROJECTS THAT EITHER, ON THE ONE HAND, MEET THE RETURN ON EQUITY THRESHOLD AND, ON THE OTHER, [redacted] EXCEED THAT THRESHOLD?

A. The simple answer is that projects with [redacted] higher projected internal rates of return are expected to be more profitable for the Company over the life of the project than projects with internal rates of return at or slightly above the return on equity threshold.

To explain, extending natural gas service to a residential development project requires the Company to make capital investments in: (1) approach mains to reach the development; (2) development mains throughout the development; and (3) services to customer homes, including the installation of metering equipment. The initial capital investment in an approach main extension would be modeled in the Company's IRRM as having been made in Year 0, or before any revenue from the project would be expected to occur. Capital investments in development mains would typically be modeled by the Company as front-loaded investments in both Year 0 and additional early years, e.g., Year 1, depending upon the development's buildout schedule. Capital investments in services would be made as homes are constructed, in the case of new developments, or

[6] *See* the Company's response to Staff interrogatory PSC-40.b.; [redacted].

upon customers “signing-up” for natural gas service in the case of conversion developments. Together these capital investments represent investments made by the Company in utility equipment and upon which the Company is entitled a reasonable opportunity to earn a fair rate of return

The return the Company receives is in the form of net cash flows over time generated by its Commission-approved rates for delivery service to customers in the residential development project, less expenses incurred by the Company to provide service. In the initial years of a project, net cash flows will be insufficient for the Company to earn its target return on equity. Depending upon the project, a crossover point will occur, e.g., in Year 10, after which net cash flows produce returns on equity equal to or exceeding the Company’s target return on equity for the remainder of the project’s life. This crossover point is influenced by: (1) the projected timetable over which customers will begin taking natural gas service, thereby generating cash inflows to the Company; and (2) the Company’s declining rate base associated with the project, which will reflect its capital investments net of accumulated depreciation and adjusted for accumulated deferred income taxes (“ADIT”).

Projects with relatively low capital investments per customer typically would be expected to produce crossover points earlier in a project’s life and achieve higher expected internal rates of return than projects with higher capital investments per customer. For example, one project with a projected capital investment of [redacted] per customer that would be completely built out by Year 2 was expected to achieve a crossover point in [redacted] and produce an internal rate of return [redacted] than another project with a capital investment of [redacted] per customer over a much longer buildout period that was expected to achieve a crossover point in [redacted], and that just met the threshold internal rate of return. As an additional example, a project with a capital investment of [redacted] per customer built out by Year 1 wasn't expected to achieve a crossover point until [redacted], yet it still surpassed the return on equity threshold.

Figure 1 presents the net cash flows for an illustrative project to depict how net cash flows are negative in the initial years of a project as the Company extends its approach and development mains, and then turn positive as customers begin taking natural gas service and generating delivery service revenues. Figure 2 shows the returns for the illustrative project stated both as a rate of return ("ROR") on rate base and a return on equity ("ROE"), as well as the thresholds for those two measures of return. Also shown in Figure 2 is the crossover point in [redacted] for both the rate of return on rate base and the return on equity. If the illustrative project was included in a Company base rate proceeding prior to the [redacted] crossover point, there would be upward pressure on the Company's revenue requirement because the project's returns were less than the thresholds, whereas there would be downward pressure on that revenue requirement in [redacted] or any year thereafter.

Figure 1

[redacted]

Source: [redacted]

Figure 2

[redacted]

Source: [redacted]

Q. PLEASE FURTHER EXPLAIN THE IMPLICATIONS OF CROSSOVER POINTS FOR EXPANSION PROJECTS IN SUBSEQUENT BASE RATE PROCEEDINGS.

A. If the aggregated rate base, revenue, and expense data for the Company's expansion projects had not yet achieved a crossover point and were included in a Company's test period for a base rate proceeding, then those projects, in aggregate, would put upward pressure on the Company's revenue requirement in that proceeding. That would occur because those projects would be producing less than the Company's threshold return on equity, thereby creating a return shortfall or revenue requirement deficiency and a need to increase delivery service rates. Likewise, if the Company's expansion projects, in aggregate, had achieved a crossover point and were producing returns greater than the Company's return on equity threshold, they would put downward pressure on the Company's revenue requirement in a base rate proceeding.

Q. IS THE POTENTIAL FOR EXPANSION AREA PROJECTS TO PUT UPWARD PRESSURE ON THE COMPANY'S REVENUE REQUIREMENT IN A BASE RATE PROCEEDING LIKELY TO REPRESENT A SIGNIFICANT ISSUE?

A. As shown in Figure 2, it will take a period of years before any given expansion project reaches a crossover point. The Company's Expansion Area program has only been in place since December 1, 2013. I would expect that few if any of its individual expansion projects have reached a crossover point. Further, its aggregated portfolio of Expansion Area projects, including projects begun more recently, clearly would not have reached a crossover point. Therefore, its Expansion Area program will put upward pressure on the

Company's revenue requirement in any base rate proceeding filed in at least the next several years.

For example, if projects that have not yet reached their crossover point have a combined rate base of $5 million that is underearning the target return on equity on a weighted average basis by 100 basis points, and correspondingly there are other projects with a combined rate base of $10 million that are overearning the target return on equity on a weighted average basis by 50 basis points, then there would be neither upward or downward pressure on the Company's revenue requirement in a base rate proceeding.[7] Given the relatively short time period during which the IES rates have been in effect and used for Expansion Area projects, the Company's current portfolio of Expansion Area projects has not yet reached that point and would, at least for a period of several more years, put upward pressure on the Company's revenue requirement in a base rate proceeding.

Q. ARE THEIR OTHER ASPECTS OF THE COMPANY'S EXPANSION AREA PROGRAM THAT COULD HAVE RATEMAKING IMPLICATIONS IN A FUTURE BASE RATE CASE?

A. Yes, there are. Inputs to the Company's IRRM that are more speculative in nature introduce risk as to whether Expansion Area projects are likely to produce the Company's projected returns for those projects, or not. The two most influential inputs to the IRRM are: (1) the number of customers that will be taking service and generating delivery service revenues, and (2) the capital costs for a project. One would expect that the Company's expertise in estimating the cost of and managing the construction of approach and development mains would materially reduce the uncertainty associated with

[7] A basis point is 1/100 of a percent. For example, a decrease in return on equity from 9.75 percent to 9.65 percent would be 0.1 percent decrease, or also a 10 basis point decrease (0.1 percent x 100 = 10 basis points).

its capital cost projections in the IRRM. Slightly less than two-thirds of the Company's delivery service revenues generated by its Expansion Area rates applicable to residential customers in its most populous residential rate class are generated by the customer charge, making projections of customers' natural gas consumption less important than projections of the number of customers that will take natural gas service and contribute to the capital costs for a project. That makes customer projections the single most influential input to the IRRM in terms of whether a project will likely produce the Company's threshold return on equity, at a minimum, because that input is both materially significant and carries with it a significant degree of uncertainty. Given the overwhelming influence of accurately predicting incremental customers on the achieved returns for any Expansion Area project, the risk of incremental customer projections that exceed actual results introduces risk that any given project could underperform financially and, in turn, produce upward pressure on the Company's revenue requirement in a base rate proceeding.

Q. DID THE PARTIES TO THE SETTLEMENT AGREEMENT APPROVED BY THE COMMISSION IN PSC DOCKET NO. 12-292 PUT PROTECTIONS IN PLACE TO ADDRESS CONCERNS YOU'VE EXPRESSED REGARDING THE POTENTIAL RATEMAKING IMPLICATIONS OF THE COMPANY'S EXPANSION AREA PROGRAM?

A. Yes. A protection was agreed to by the parties to the settlement agreement filed in PSC Docket No. 12-292 that states:

> [I]f at the time of the next base rate proceeding, the results of the aggregated IRRM for all Expansion Area projects demonstrate that the Company earned a rate of return on the aggregated projects less than

7.77%, then 50% of the shortfall will be deducted from rate base for ratemaking purposes. The remaining 50% of the shortfall would be eligible for recovery in such rate proceeding pursuant to the rules and regulations of the Commission and applicable law. The amount of the shortfall shall be equal to the amount of the contribution in aid of construction that would otherwise be necessary in order for the Company to have earned a return of 7.77% on the aggregated projects.[8]

Approximately two years after the settlement agreement was approved by the Commission in PSC Docket No. 12-292, the Company filed a base rate case that was docketed as PSC Docket No. 15-1734 (the "2016 Rate Case"). That case was also resolved with a settlement agreement, which the Commission approved in Order 8982.[9] The settlement agreement resolving the 2016 Rate Case was silent as to either: (1) any rate base disallowances resulting from the Expansion Area projects underearning a 7.77 percent rate of return on rate base, in aggregate; and (2) any protections going forward should the Expansion Area projects be in an underearning position, in aggregate, at the time of any subsequent base rate proceeding. Further, because the protection negotiated into the settlement agreement resolving PSC Docket No. 12-292 was only applicable to the "next" base rate proceeding, that protection has expired. As a result, there are no current protections in place to guard against the Expansion Area projects underearning threshold levels of return.

Q. DO YOU HAVE PARTICULAR CONCERNS GIVEN THE FACT THAT THERE ARE NO PROTECTIONS IN PLACE TO GUARD AGAINST THE

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[8] PSC Docket No. 12-292, *Order 8479*, Attachment A, *Proposed Settlement*, p. 4 (November 6, 2013)
[9] PSC Docket No. 15-1734, *Order 8982* (December 21, 2016).

EXPANSION AREA PROJECTS UNDEREARNING AT THE TIME OF THE COMPANY'S NEXT BASE RATE PROCEEDING?

A. Yes, I do. First, until the Company's Expansion Area program matures further, there is the risk I discussed previously that the aggregated results for the Expansion Area projects have not yet achieved a crossover point and they will put upward pressure on the Company's revenue requirement in the next base rate proceeding. Second, any protection that utilizes aggregated results masks the potential risks inherent in the Company's Expansion Area program where it is essentially placing a capital investment bet on the housing market with each new project that it proceeds with, and that entails significant risk, not to the Company but to its existing customers. Consider an example where the Company invested over one million dollars on an approach main for a development with an anticipated multi-year buildout of approximately 500 customers just prior to, but in the early indications of, a housing market downturn, and then found itself in a position where revised customer estimates would not exceed 100 anytime in the foreseeable future. That capital investment in a relatively large Expansion Area project could roll into the Company's rate base in a base rate proceeding, and without anywhere near the revenue stream to support that investment. If that investment was aggregated into the Company's entire portfolio of Expansion Area projects, the portfolio could still be achieving results at or above the Company's target return on equity, thereby absolving management of any responsibility for the ill-fated investment. Given the fact that the Company management is far more capable of monitoring the risk of housing market fluctuations than its existing customers, particularly given its ongoing prospecting efforts for additional projects to develop in the Expansion Area, the risk of imprudent decisions on management's part for any given project should be left on the table for subsequent base rate proceedings, and not shifted to existing customers through aggregated protection mechanisms.

Q. IN YOUR PREVIOUS ANSWER YOU SAID THE COMPANY IS INVOLVED IN "ONGOING PROSPECTING EFFORTS FOR ADDITIONAL PROJECTS TO DEVELOP IN THE EXPANSION AREA." PLEASE EXPLAIN THE BASIS FOR YOUR STATEMENT.

A. The Company has indicated that it is in discussions with housing developers regarding additional projects in the Expansion Area.[10] That is very much in line with the Company's overall strategy for its regulated natural gas distribution businesses—grow the business and thereby contribute to corporate earnings per share growth.[11,12]

Q. BASED UPON YOUR REVIEW OF THE COMPANY'S EXPANSION AREA PROJECTS, WOULD YOU CONSIDER THE COMPANY'S EXPANSION AREA PROGRAM PUT IN PLACE BEGINNING IN DECEMBER 2013 FOLLOWING PSC DOCKET NO. 12-292 TO BE A SUCCESS?

A. From the public policy perspective of giving additional Delaware residents and businesses an alternative form of energy that they could choose to utilize, yes, I consider the Company's Expansion Area program to be a success. From the perspective of the Company's shareholders, I also would consider the program to be a success—the

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[10] *See* the Company's response to Staff interrogatory PSC-40.c.-d.; [redacted].

[11] *See* Attachment DDE-1, p. 2, Excerpts from the Company's 2017 Annual Report to Shareholders; "Highlights of our powerful growth in 2017 include: Chesapeake Utilities and FPU increased their customer bases and continued to extend natural gas distribution services on both the Delmarva Peninsula and in Florida. Additionally, Sandpiper Energy increased the energy options available for residents of Ocean City, MD."

[12] *See* Attachment DDE-2, pp. 2-3, Excerpts from the Company's Mid-Atlantic Road Show Presentation (March 2018); "Strategic Platform for Sustainable Growth, Developing New Business Opportunities and Executing Existing Business Unit Growth, Maximize Growth in Existing Footprint and Expand Into New Territories, • Maximize organic growth in existing geographic footprint, • Expand into new geographic areas, • Develop additional growth across business units."

Company is leveraging the program to grow its rate base and, in turn, corporate earnings per share.[13] From the perspective of existing customers, the program has probably not been either detrimental or necessarily beneficial. I say that because the effect of the program on the rates approved by the Commission in the 2016 Rate Case was not explicitly addressed, so the benefits to existing customers from the program will have to be addressed in a future base rate proceeding.

Q. DO YOU THINK IMPROVEMENTS COULD BE MADE TO THE COMPANY'S EXPANSION AREA PROGRAM?

A. I do, and it is my recommendation that changes to the program be considered in the context of the Company's current Application in this proceeding to expand the IES rate offering throughout its service territory. Specifically, the Commission should consider:

- Re-addressing the balance of risk and reward between the Company and existing customers; and
- Charting a course forward that will result over time in the customer charges for maturing Expansion Area projects to fall back in line with non-Expansion Area customer charges.

Q. WHAT DO YOU MEAN BY MATURING EXPANSION AREA PROJECTS?

A. I use the term "maturing" to refer to those Expansion Area projects that have passed their crossover point and are producing returns above the Company's target return on equity.

[13] *See* Attachment DDE-3, pp. 1-2, Excerpts from the Company's Annual 10k Filings with the Securities and Exchange Commission; customer growth in the Company's distribution operations are producing gross margin increases.

IV. BALANCING RISK BETWEEN THE COMPANY AND EXISTING CUSTOMERS

Q. HAS THE COMPANY BEEN ADEQUATELY REWARDED FOR THE RISKS IT HAS UNDERTAKEN IN EXTENDING NATURAL GAS SERVICE IN THE EXPANSION AREA?

A. Because the 2016 Rate Case was resolved with a "black-box" settlement agreement, no explicit determination was made as to whether the Company either financially benefited from or was negatively affected by its actions to extend natural gas service to projects in the Expansion Area in the relatively short period of time between December 1, 2013, when the Expansion Area rates became effective, and when the 2016 Rate Case was filed using a test period ending March 31, 2016.[14]

The Company did report in the 2016 Rate Case that its main extensions over 500 feet for the period subsequent to March 31, 2007 through September 24, 2015, some of which were made in the Expansion Area, were very profitable for the Company, with all extensions producing an aggregate rate of return on rate base of 10.47 percent, or well in excess of the required rate of return on rate base of 8.91 percent.[15] Using the cost of capital established in the settlement agreement that resolved PSC Docket No. 07-186 (the "2008 Rate Case"), a return on rate base of 10.47 percent translates into a very lucrative return on equity to the Company of 12.8 percent for its main extensions during that period.[16] By that measure, the Company has been well rewarded financially for the risks it has undertaken in extending its mains to provide natural gas service to new residents and businesses throughout its service territory, including the Expansion Area. Moreover,

[14] PSC Docket No. 15-1734, *Application*, paragraph 4; "[t]he proposed rates are based on a historic test year of the twelve-month period ending June 30, 2015, and a test period of the twelve-month period ending March 31, 2016."
[15] PSC Docket No. 15-1734, *Direct Testimony of Jeffrey Weiss*, pp. 7-8 (December 21, 2015).
[16] *See* the Company's response to Staff interrogatory PSC-2.a.; the capital structure established in PSC Docket No. 07-186 for use in the Company's IRRM included a debt/equity ratio of 38.15 percent / 61.85 percent and a cost of debt of 6.74 percent.

that return on equity figure is understated because the Company's cost of debt decreased between the 2008 Rate Case and the 2016 Rate Case.

Q. WHY WOULD A DECREASED COST OF DEBT CAUSE THE RETURN ON EQUITY FOR THE COMPANY'S MAIN EXTENSIONS BETWEEN MARCH 31, 2007 AND SEPTEMBER 24, 2015 TO BE UNDERSTATED?

A. A lower cost of debt reduces the Company's interest expense, thereby increasing its net cash flows for any main extension, which translates into a higher internal rate of return, i.e., higher return on equity.

Q. BY HOW MUCH DO YOU THINK A RETURN ON EQUITY FIGURE OF 12.8 PERCENT UNDERSTATES THE COMPANY'S ACTUAL RETURN ON EQUITY FOR MAIN EXTENSIONS BETWEEN MARCH 31, 2007 AND SEPTEMBER 24, 2015?

A. To gain a general idea of the potential magnitude by which a 12.8 percent return on equity figure could understate the financial reward the Company enjoyed from its main extensions over those eight and one-half years, I adjusted the Company's IRRMs for two projects using a cost of debt of 5.78 percent, or the average of 6.74 percent from the 2008 Rate Case and 4.82 percent reported in the 2016 Rate Case.[17] Lowering the cost of debt from 6.74 percent to 5.78 percent increased the internal rates of return for those two projects by [redacted], respectively, so it would not be at all unreasonable to conclude that the Company earned a return on equity well in excess of 13.0 percent on main extensions for that period. Again, the Company clearly has been well rewarded financially for the risks it has undertaken with its main extensions.

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[17] PSC Docket No. 15-1734, *Direct Testimony of Paul R. Moul*, p. 20 (December 21, 2015); "{t]he embedded cost of long-term debt is expected to be 4.82% at March 14 31, 2016." *See also* the Company's responses to Staff interrogatory PSC-2, a.-b. for the IRRMs.

Q. IS THE COMPANY EXPOSED TO RISK ASSOCIATED WITH ITS COMMISSION-APPROVED EXPANSION AREA PROGRAM AND LINE EXTENSTION POLICY?

A. At present, the Company faces minimal risk associated with its Commission-approved Expansion Area program and line extension policy. It will extend natural gas service within the Expansion Area only to projects that meet or exceed its return on equity threshold in its IRRM, so its expectations going into a project based upon the inputs it uses in its IRRM are that the project will be profitable for its shareholders over the life of the project. If a project fails to achieve earnings equal to or exceeding its target return on equity, either because it has not yet reached its crossover point and become profitable or the Company's IRRM inputs did not reflect actual results, then the Company can turn to the Commission for revenue relief by filing a base rate case to make up any return on equity shortfall. Likewise, main extensions outside of the Expansion Area that fall short of return on equity expectations can be addressed in base rate proceedings. Therefore, the Company's risk associated with its Expansion Area program and line extension policy is related primarily to return on equity shortfalls between base rate proceedings.

The other risks the Company is exposed to relate to execution risk, i.e., whether it constructs a line extension prudently and is not therefore exposed to a cost disallowance in a base rate proceeding, and administrative risk, i.e., whether it diligently adheres to its line extension policy credit protocols.[18]

Q. DO EXPANSION AREA CUSTOMERS TAKE ON ANY RISK WHEN THEY AGREE TO RECEIVE NATURAL GAS SERVICE FROM THE COMPANY?

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[18] *See* Rules and Regulations Governing the Distribution and Sale of Gas of Chesapeake Utilities Corporation in New Castle, Kent & Sussex Counties, Delaware, Section 13.2 Establishment of Customer Credit.

A. Expansion area customers that make a capital investment to utilize natural gas service in lieu of an alternative source of energy take on risk related to uncertain returns on that capital investment. That would be the case for an Expansion Area conversion project, where customers must make capital investments in appliances, etc., to utilize natural gas service. Their return on their capital investment comes primarily from fuel cost savings over time but could also come in the form of an increase in the sales price for the home or business because it has natural gas service. With fuel cost savings as the primary value driver, the time a customer remains in its home or business and benefits from those fuel cost savings is an important determinant for the actual return a customer earns from making a capital investment to utilize natural gas service.

Expansion area customers that purchase a new home or commercial establishment that is already capable of utilizing natural gas do not take on any risk for that decision, setting aside the premium they may have paid, if any, for that new home or establishment because it can utilize natural gas.

Q. ARE NON-EXPANSION AREA CUSTOMERS EXPOSED TO RISKS ASSOCIATED WITH THE COMPANY EXTENDING NATURAL GAS SERVICE TO CUSTOMERS IN THE EXPANSION AREA?

A. That depends upon the regulated ratemaking process applied to the Company, and specifically the ratemaking provisions applicable to its Expansion Area program and line extension policy in general. Utility line extension policies have been developed and implemented to strike a reasonable balance between new customers and existing customers, while also providing protections for utilities that must abide by those line extension policies. When a utility acts prudently and diligently adheres to those policies, its primary risk is return on equity shortfalls produced by the line extension policy, and for which it has a remedy—base rate case applications. A utility's existing customers face the risk that the utility will in fact employ that remedy and file an application to increase their rates to eliminate a return on equity shortfall arising from capital investments to serve new customers under the line extension policy. The Company's non-Expansion Area customers face that very real risk, that they will be used as the backstop protection for any Company return on equity shortfall resulting from the Expansion Area program. In addition, all existing non-Expansion Area and Expansion Area customers face the risk that any given incremental Expansion Area project will fail to achieve financial expectations and expose them to a return on equity shortfall for that project, and upward pressure on the Company's revenue requirement in a base rate proceeding.

Q. GIVEN THE COMPANY'S CURRENT APPLICATION REQUESTING TO UTILIZE THE IES RATES THROUGHOUT ITS SERVICE TERRITORY, DO YOU THINK IT IS APPROPRIATE FOR THE COMMISSION TO REVISIT THE RELATIVE BALANCE OF RISK BETWEEN THE COMPANY AND CUSTOMERS?

A. Yes, I do.

Q. HOW DO YOU THINK THE RELATIVE BALANCE OF RISK SHOULD BE CHANGED?

A. I think existing customers' risk exposure should be reduced somewhat, and by existing customers I am referring to both customers not under the IES rates and customers that have previously begun service under the IES rates, as both are existing customers.

Q. WHY DO YOU THINK EXISTING CUSTOMERS' RISK EXPOSURE SHOULD BE REDUCED?

A. The Company's business strategy is to promote the expansion of natural gas service throughout its service territory. Doing so allows it to grow its rate base and, in turn, make a positive contribution to increasing the Company's corporate earnings per share. The Company's existing Expansion Area program and its request in this case to utilize the IES rates throughout its service territory fit perfectly within that strategy. Further, its Expansion Area program sets the stage for incremental capital investment and earnings per share growth as the Company leverages approach main extensions made under the program to reach further into the Expansion Area and reach new projects.

As I said previously, I view the Expansion Area program as a success for the Company, and from a public policy perspective, while the benefits for existing customers have yet to be determined. Given the overall success of the program for the Company and its shareholders, it would be appropriate for the Commission to consider additional protections for existing customers as an appropriate balance to the value the program is producing for Company shareholders.

Q. WHAT TYPE OF PROTECTIONS COULD BE ADDED TO PROTECT EXISTING CUSTOMERS FROM THE RISKS OF EXPANSION PROJECTS?

A. The risks existing customers face that they will be exposed to Company return on equity shortfalls in a base rate proceeding are twofold: (1) projects to which the IES rates have been applied have not in aggregate reached a crossover point, and (2) any individual project fails to achieve return on equity projections. Protections that reduce the risk of any individual project failing to achieve expectations or that place risk on the Company for a portion of return on equity shortfalls for its portfolio of expansion projects will reduce risk to existing customers.

Striking a balance between reducing the risk to existing customers while not negatively and materially affecting the Company's ability to continue expanding natural gas service to customers that avail themselves of the IES rates is not necessarily easy to accomplish nor straightforward. Any measures that increase costs for developers or customers willing to pay the IES rates could negatively affect the expansion of the availability of natural gas service in the Company's service territory.

As I discussed previously, a significant risk to the financial success of any individual project is whether the number of customers projected to take natural gas service in fact do take natural gas service. For new housing developments, that risk lies with how quickly homes are built, purchased and occupied, such that delivery service revenues are generated to provide a return on capital invested in the project. For conversion projects, that risk lies with how many customers in fact convert to natural gas service. Financial assurances required from developers to adhere to buildout schedules would reduce the risk to existing customers but could receive significant pushback from developers. Likewise, financial assurances required from prospective customers in a conversion project, e.g., a refundable deposit, before including that customer in the Company's IRRM would reduce risk to existing customers but could also receive pushback. Both could improve the status quo and could be considered. However, I've focused on areas where additional risk could be shifted to the Company, and away from existing customers, without negatively affecting developers or prospective conversion area customers.

Specifically, I think an aggregated expansion portfolio minimum return protection similar in construct to what the parties agreed to in PSC Docket No. 12-292 would be appropriate to implement with the current case, particularly since that prior protection has expired. In addition, I think protections should be added for individual projects because without those protections the negative effects of capital investments made by the Company in potentially ill-fated projects, possibly during a housing market downturn, could be swept into and masked in the aggregated portfolio protection.

Q. DO YOU HAVE A SPECIFIC RECOMMENDATION REGARDING AN AGGREGATED EXPANSION PORTFOLIO MINIMUM RETURN PROTECTON?

A. Yes, I do. The parties to the settlement agreement in PSC Docket No. 12-292 agreed that the Company would be exposed to a downward rate base adjustment if its portfolio of Expansion Area projects failed to achieve a threshold rate of return on rate base. That presented a risk to the Company if it were to file a base rate application knowing that its aggregated portfolio of Expansion Area projects had not yet sufficiently matured and could produce a rate base disallowance. That risk would have to be balanced against the Company's internal projections of its return on equity shortfall when arriving at a decision as to whether to file a base rate case application. Essentially, that protection could cause the Company to defer a base rate case application, thereby benefiting existing customers, or it could result in a disallowance if the Company did file a base rate case application, also resulting in a benefit for customers.

Given the strategic value of the Expansion Area program to the Company's shareholders, and given the strategic value it would gain if it were allowed to utilize IES rates throughout its service territory, it would be appropriate in my opinion for the Commission to adopt a variation on the aggregated protection the parties agreed to in PSC Docket 12-292 that increases the rate of return on rate base threshold for determining rate base disallowances in a base rate proceeding by 50 basis points above the authorized rate of return in that proceeding. Using the language agreed to by the parties in that docket as a starting point, I recommend the following language to incorporate my suggested variation to that protection:

> If at the time of the next base rate proceeding, the results of the aggregated IRRM for all projects that are utilizing the IES rates, excluding projects (1) where approach or development mains capital investment began prior to December 1, 2013, (2) have not yet begun producing delivery service revenues, and (3) where approach or development mains began more than ten years prior to the end of the last day of the test period, demonstrate that the Company earned a rate of return on the aggregated projects less than the authorized rate of return determined in that proceeding plus 50 basis points, then 50 percent of the shortfall will be deducted from rate base for ratemaking purposes. The remaining 50 percent of the shortfall would be eligible for recovery in such rate proceeding pursuant to the rules and regulations of the Commission and applicable law. The amount of the shortfall shall be equal to the amount of the contribution in aid of construction that would otherwise be necessary for the Company to have earned a return equal to the authorized rate of return determined in that proceeding plus 50 basis points on the aggregated projects.

Q. WHY DO YOU THINK IT WOULD BE APPROPRIATE TO UTILIZE THE RATE OF RETURN AUTHORIZED BY THE COMMISSION IN A BASE RATE PROCEEDING IN THE AGGREGATED PROTECTON MECHANSIM YOU'RE RECOMMENDING?

A. That level of return would represent the most up-to-date and accurate determination of the Company's required rate of return, with the most current estimates of its cost of capital and appropriate capital structure. Previously determined rates of return would represent stale data, thereby creating a situation where the Company could benefit or be harmed by changes in its cost of debt, cost of equity, or capital structure in the application of the protection mechanism, while utilizing the most currently available rate of return would not lead to such a situation.

Q. WHY ARE YOU RECOMMENDING THAT THE AGGREGATED PROTECTION MECHANISM INCLUDE 50 BASIS POINTS ABOVE THE AUTHORIZED RATE OF RETURN ON RATE BASE TO ESTABLISH A THRESHOLD AS TO WHETHER THERE WOULD BE A RATE BASE ADJUSTMENT IN A RATE PROCEEDING?

A. I recommend including the additional 50 basis points to reflect the fact that the Company's expansion program has strategic value to the Company that it would continue to pursue even with an added element of risk.

Q. WHY DID YOU LIMIT THE PROJECTS TO BE INCLUDED IN THE AGGREGATED IRRM TO PROJECTS WHERE APPROACH AND DEVELOPMENT MAINS CAPITAL INVESTMENT BEGAN WITHIN TEN YEARS OF THE LAST DAY OF THE TEST PERIOD IN THE BASE RATE PROCEEDING?

A. As the Company's aggregated portfolio of expansion projects matures, it will reach a crossover point after which it will never be susceptible to falling below the Company's authorized return in a base rate proceeding, except possibly following a significant housing cycle downturn just after passing that crossover point. Therefore, a rolling ten-year aggregated portfolio test as I recommend provides a meaningful protection for customers, whereas, for example, a 15-year aggregated portfolio test would not.

Q. WHAT RISK MITIGATION PROTECTIONS ARE YOU RECOMMENDING FOR INDIVIDUAL PROJECTS?

A. I recommend that the Company bear additional risk for any individual projects with either: (1) capital investments in approach mains equal to or greater than $500,000, or (2) actual buildouts that exceed 36 months. For those projects, if actual customers fall more than 15 percent below the customer projections used by the Company in its IRRM, the Company's rate base will be subject to a reduction in a base rate proceeding. To explain, if the Company's IRRM using the authorized rate of return in a rate proceeding projected a rate of return of [redacted] percent in [redacted] for a project (*see* Figure 2 for example), and [redacted] also corresponded to the test period in the rate proceeding, and the project's customer count was more than 15 percent below the Company's IRRM projection when it undertook the project, then rate base would be adjusted to bring the project's rate of return up to the level the IRRM would produce for [redacted] with a customer count set equal to 15 percent below the Company's customer projection.

Specifically, I recommend the following language for protections on individual projects:

> If at the time of the next base rate proceeding, the results of the IRRM for individual projects either with (1) actual capital investment in approach mains equal to or greater than $500,000, or (2) actual buildouts that exceed 36 months, and where actual customers have fallen more than 15 percent below the Company's projections in its IRRM, then the Company's rate base for that project will be reduced so that the rate of

> return generated by the IRRM would be equivalent to a customer count equal to 15 percent below its projections and using the authorized rate of return determined in that rate proceeding. The rate base reduction shall be equal to the amount of the contribution in aid of construction that would otherwise be necessary for the Company to have achieved the IRRM's projected return for the base rate proceeding test period using a customer count equal to 15 percent below its projections and using the authorized rate of return determined in that proceeding.

So as not to penalize the Company twice for the same project with the two risk mitigation measures that I recommend, that is, once with an individual project rate base adjustment for lagging customer counts, and then again to the extent that individual project could contribute to an aggregated portfolio return shortfall, I recommend that any rate base reduction for an individual project also be deducted from the aggregated portfolio before determining whether there will be an aggregated portfolio rate base adjustment, if any.

Q. WOULD THE RISK MITIGATION MEASURE FOR INDIVIDUAL PROJECTS THAT YOU'RE RECOMMENDING POTENTIALLY INFLUENCE THE COMPANY TO LOWER ITS CUSTOMER COUNT PROJECTIONS TO REDUCE THE RISK THAT A PROJECT'S ACTUAL CUSTOMERS WILL FALL MORE THAN 15 PERCENT BELOW PROJECTIONS?

A. There is the potential for the Company to react to this mitigation measure by introducing a downward bias into its customer projections, particularly if a project's economics are above the threshold return on equity. In other words, even a lower customer projection would allow the project to pass the IRRM's return requirements, thereby allowing the Company to proceed with the project while at the same time reducing its exposure to this risk mitigation measure. For projects that are very close to but above the return threshold, materially reducing the customer projection would make the project uneconomic. Despite the potential introduction of bias into the Company's customer projections, the risk mitigation measure I'm recommending for individual projects still has merit.

<u>V. CHARTING A COURSE TOWARD EQUALIZED CUSTOMER CHARGES</u>

Q. DO YOU HAVE CONCERNS WITH THE IES RATES PRODUCING DIFFERENT CUSTOMER CHARGES FOR EXPANSON PROJECT CUSTOMERS COMPARED WITH THE CUSTOMER CHARGES FOR NON-EXPANSION AREA CUSTOMERS?

A. Yes, I do. The current path forward would leave the IES rates in place for the life of expansion projects, or over 50 years following the Company's last capital investment in a project given the depreciable life of the Company's equipment. Large differentials in customer charges for what customers rightfully would understand to be the same service can and will likely lead to customer confusion and customer complaints. Explaining to a customer in an expansion project that its customer charge will be higher than the Company's general population of customers because the higher customer charge was required to make it economical to extend natural gas service to the project is both reasonable and something a customer is likely to understand, provided the customer is either the owner of a new home in an expansion project or a home in a conversion project. However, the median homeownership tenure in the U.S. is about eight and one-half years.[19] As homes in expansion projects turnover and new owners become subject to IES rates and higher customer charges, the strength of any argument that they should be paying more in the way of customer charges then, for example, their golfing buddy or a parent of one of their children's friends, is greatly reduced, not from a pure financial perspective but from the perspective of whether that argument will be persuasive to the customer paying the higher customer charge. The argument becomes even weaker and less persuasive with each successive house turnover, no matter how sound the argument is financially. Therefore, from a public policy perspective, I recommend that the Commission chart a course toward equalizing the customer charges for mature expansion projects with those paid by customers not receiving service under the IES rates.

Q. WHAT DO YOU MEAN BY THE TERM "MATURE" EXPANSION PROJECTS?

A. I use the term mature to refer to expansion projects that are producing returns that exceed the Company's authorized return on equity, and also its authorized rate of return on rate base.

Q. CAN YOU PROVIDE EXAMPLES OF HOW TO IMPLEMENT THE EQUALIZATION OF CUSTOMER CHARGES FOR MATURE EXPANSION PROJECTS AND CUSTOMERS NOT RECEIVING SERVICE UNDER IES RATES?

A. One way to move toward equalized customer charges for mature expansion projects and customers not receiving service under IES rates would be reduce IES rates for a block of mature expansion projects, e.g., those that are between 11 and 15 years old, by one-half in a base rate proceeding, with the revenue shortfall shifted to all other customers'

[19] Dougherty, Conor, *Real Estate's New Normal: Homeowners Staying Put* (May 14, 2017); available at https://www.nytimes.com/2017/05/14/business/economy/home-ownership-turnover.html.

delivery service rates. A second and final adjustment to equalized rates could be made in a subsequent base rate proceeding for that same block of expansion projects after they've further matured, again with the revenue shortfall shifted to all other customers' delivery service rates. The problem with this option for pursuing equalized rates is that base rate proceedings already typically entail increases in rates for all customers, and additional revenue shifts between customers become more difficult to implement in that situation, purely from the perspective of whether customers on the receiving end of the revenue shift can be made to understand the reasonableness of the action being taken.

Another option would be to establish a sunset provision for IES rates for every expansion project, e.g., IES rates would not apply to a home or business after 15 years. While likely feasible to implement, that option would also likely be administratively burdensome for the Company if applied to each expansion customer individually. Further, it would represent a base rate reduction for the Company outside of a base rate proceeding, and that is problematic from the perspective of equitable ratemaking. An additional concern from a public policy perspective would be that a sunset provision on IES rates would negatively affect the economics of expansion projects, particularly if the sunset was relatively early in the life of the project, e.g. 15 years. For example, Figure 3 shows the returns for the illustrative project that I addressed above (*see* Figure 2), but without the IES rate beginning in Year 16. With this illustrative example, the project will not pass the IRRM return thresholds over the life of the project, with the internal rate of return decreasing by approximately [redacted] basis points due to the elimination of the IES rate in Year 16. Further, if rolled into a base rate proceeding, this project would shift costs to other customers anytime its returns were below the thresholds shown in Figure 3, which would be all years except [redacted], and [redacted] and thereafter.

Figure 3

[redacted]

Source: [redacted]

Reducing the IES rates over time, for example at five-year intervals, can result in the elimination of the IES rates without putting upward pressure on the Company's revenue requirement in a base rate proceeding. Figure 4 shows returns for the illustrative project with IES rate reductions in Years 16, 21, 26, and 31 of $7.25, $6.25, $3.00, and $2.25, respectively. Importantly, at no time after [redacted] did the project's returns fall below the threshold returns, thereby preventing upward pressure on the Company's revenue requirement. However, the project would still not pass the IRRM return thresholds, with the internal rate of return decreasing by approximately [redacted] basis points. Further, each reduction in the IES rates entails a shift in revenues to other customers in a base rate proceeding, despite the fact that the IES rate reduction does not put upward pressure on the Company's revenue requirement, and that presents a ratemaking challenge.

Figure 4

[redacted]

Source: [redacted] The four illustrative reductions to IES rates total $18.75.

An important consideration for charting a path toward equalized customer charges for IES customers and non-IES customers is the initial step in the right direction at a reasonably early point in the future because, thereafter, it becomes easier to make additional progress as illustrated with the declining adjustments to the IES rates shown in Figure 4. The real challenge then is how to get started when a reasonably sufficient initial reduction in IES rates will shift a portion of the Company's revenue requirement in a base rate proceeding to other customers.

As a purely illustrative example, the Company's delivery service rates in a base rate proceeding could be designed to over-collect its revenue requirement, with the resulting over-collection recorded by the Company as a regulatory liability. That regulatory liability would increase over time and could be utilized thereafter in a base rate proceeding to reduce the IES rates. In other words, in the subsequent base rate proceeding the regulatory liability and IES rates would be correspondingly reduced for a block of expansion projects that had sufficiently matured.

Q. DO YOU THINK CHARTING A PATH FORWARD TOWARD EQUALIZED CUSTOMER CHARGES FOR IES AND NON-IES RATE CUSTOMERS SHOULD BE RESOLVED IN THIS PROCEEDING?

A. I don't think it necessarily has to be resolved in this proceeding but charting a course forward should be addressed sooner rather than later, and certainly no later than the Company's next base rate proceeding.

<u>VI. IMPLICATIONS OF THE CHANGE IN FEDERAL INCOME TAX LAW</u>

Q. HAVE YOU REVIEWED DOCUMENTS FILED IN PSC DOCKET NO. 17-1240 THAT WAS OPENED BY THE COMMISSION TO REVIEW THE EFFECTS OF THE TAX CUTS AND JOBS ACT OF 2017?

A. Yes, I reviewed the Petition of the Delaware Division of the Public Advocate ("DPA"), the Commission's orders, and the Company's filing in that docket. Of specific interest to me was the Company's estimates of the effect on its delivery service rates required to flow through the benefits of the reduced corporate income tax enacted with The Tax Cuts and Jobs Act of 2017 ("TCJA"). I wanted to understand how changes to the delivery service rates and the new corporate income tax rate of 21 percent would affect the internal rates of return for projects the Company had modeled in its IRRM. Specifically, I wanted to understand if the combined effect of lower delivery service rates and a lower corporate income tax rate would improve the economics of expansion projects.

Q. WHAT WERE YOU ABLE TO DETERMINE?

A. The combination of lower delivery service rates, which reduced project profitability, and a 21 percent corporate income tax rate, which increased project profitability, produced [redacted] of the one expansion project that I tested. [redacted]

Q. HOW DO THOSE RESULTS AFFECT THE CURRENT PROCEEDING?

A. [redacted]

VII. ACQUIRED COMMUNITY GAS SYSTEMS RATE BASE VALUATION ISSUE

Q. ON FEBRUARY 4, 2016, IN PSC DOCKET NO. 16-0161, THE COMPANY FILED AN APPLICATION TO ADOPT PROCEDURES GOVERNING THE ACQUISITION AND CONVERSION OF PROPANE COMMUNITY GAS SYSTEMS TO NATURAL GAS SERVICE. BRIEFLY DESCRIBE THE COMPANY'S APPLICATION IN PSC DOCKET NO. 16-0161.

A. In PSC Docket No. 16-0161, the Company sought to establish, among other things, an accounting treatment for the acquired community gas systems ("CGS") to be used for ratemaking purposes, and a rate structure for CGS customers that convert to natural gas service. The pricing structure proposed by the Company included a separate calculation of an additional fixed cost amount to be added to the converting customers' monthly customer charge for each CGS acquisition.

Q. ARE YOU ADDRESSING, OR IS IT APPROPRIATE TO ADDRESS, THE RATES TO BE CHARGED TO CONVERTING CGS CUSTOMERS FOR NATURAL GAS SERVICE IN THIS PROCEEDING?

A. No. The most significant issue to be addressed in PSC Docket No. 16-0161 is the accounting ratemaking treatment of the CGS acquired by the Company. That is, how should the value of the CGS acquired by the Company be reflected in rate base. This issue is not being addressed in the instant proceeding. It would be premature to address the rate setting process for natural gas service to CGS customers prior to resolving the CGS rate base valuation issue.

VIII. CONCLUSION AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Company's Expansion Area program has been a strategic success for the Company and being able to offer IES rates throughout its service territory as the Company is requesting with its Application falls right in line with its business strategy to grow its business and make a positive contribution to corporate earnings per share growth. Each expansion project offers the potential that investments in approach mains can be leveraged to serve successive expansion projects, thereby increasing the inherent value of each expansion project to the Company. [redacted]

Protections for existing customers against upward pressure on the Company's revenue requirement in base rate proceedings arising specifically because of an immature portfolio of expansion projects was an important consideration when the Commission approved the IES rates, and it is an important consideration today. Existing customers, both those that do not pay the IES rates and those that previously began paying those rates, should be afforded some level of protection against upward pressure on the Company's revenue requirement in a base rate proceeding that results from the Company's expansion efforts. I propose two risk mitigation measures to provide existing customers with protection from that situation. One is a protection against individual projects involving either large capital investments or relatively long buildouts, both of which pose a greater risk to existing customers. In addition, I propose a risk mitigation measure to address the overall performance of the Company's aggregated portfolio of expansion projects, with that measure being a variation on the measure that the Commission approved in PSC Docket No. 12-292, and which strikes a better balance between the risks to existing customers and the strategic value of expansion projects for the Company.

With the Commission's approval of the risk mitigation measures that I recommend, it would be reasonable for the Commission to approve the Company's request in this proceeding to be able to offer the IES rates throughout its service territory. However, Staff is opposed to the Company's request without those risk mitigation measures.

Finally, charting a course toward equalized customer charges for IES rate customers and non-IES rate customers is an important public policy issue that warrants discussion in this proceeding and the selection of a path forward sooner rather than later.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. The Commission should approve the Company's request to offer IES rates throughout its service territory with the risk mitigation measures that Staff proposes. Specifically, those risk mitigation measures should provide protection for existing customers against upward pressure on the Company's revenue requirement in a base rate proceeding for:

- Individual expansion projects that fall more than 15 percent below the Company's customer projections and with either: (1) capital investments in approach mains equal to or greater than $500,000, or (2) actual buildouts that exceed 36 months.
- A situation where the Company's rate of return on rate base for its aggregated portfolio of expansion projects falls below the authorized rate of return determined in that proceeding, plus 50 basis points, and where the aggregated portfolio of expansion projects includes projects undertaken since December 1, 2013, but not to exceed the ten years ending with the end of the test period in the base rate proceeding.

Without those important risk mitigation measures to protect existing customers against undue upward pressure on their rates, the Commission should not approve the Company's request in this proceeding.

Further, the Commission should begin the process of charting a course forward for equalizing the customer charges for IES and non-IES customers. Accomplishing that important public policy objective will take time, but the path forward needs to be charted sooner rather than later.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

APPENDIX

QUALIFICATIONS OF

DWIGHT D. ETHERIDGE

DWIGHT D. ETHERIDGE

Mr. Etheridge is a principal at Exeter Associates, Inc. with thirty-two years of wide ranging experience in the electric utility industry. His areas of expertise include business plan development, industry restructuring, rate design, class cost-of-service studies, load forecasting, resource planning, transmission system evaluations, power procurement, utility benchmarking studies, distributed generation, telecommunications, and contract negotiations.

His management experience includes reporting to the CEO of a western utility during electric deregulation and a merger of two utilities, advising the CEO on many topics including regulatory issues, legislative negotiations, strategic focus, decision analysis, and merger integration. He also has substantial project management experience gained as a consultant and in various progressively more responsible leadership roles in utility management.

Mr. Etheridge has extensive experience developing analytical and strategic solutions on a variety of utility issues and communicating on those issues to regulatory commissions, legislatures, senior management, board of directors and the public. He has presented expert testimony on thirty-seven occasions and has acted as a spokesperson numerous times on television, radio and in print.

Education:

B.S. (Business Administration) – University of California, Berkeley, 1985.

Previous Employment:

2004-2005 - Independent Strategy and Business Consultant

1999-2004 - Strategic Director, Sierra Pacific Resources and its Subsidiaries

1986-1999 - Nevada Power Company
- Leader of the Industry Restructuring Team
- Director, Pricing and Economic Analysis
- Economist
- Load Forecast Analyst

Professional Work:

Mr. Etheridge's work at Exeter Associates, Inc. has been focused in the following areas:

Contract negotiations for electricity and natural gas supply for U.S. Department of Energy (DOE) facilities.

Fuel switching studies for DOE facilities.

Development of electricity and renewable energy procurement plans and risk management strategies for DOE's Northern California national laboratories.

Natural gas options analyses and development of models to project implied volatilities.

Review of utility procurement strategies for multiple U.S. Air Force bases to identify areas for potential utility cost savings.

Evaluating the need for new transmission lines in the PJM market on behalf of an agency of the State of Maryland.

Provided analytical support to a southwestern municipal water and power utility in the areas of rate design, load forecasting, wholesale market modeling, and volatility analysis.

Review of the Regional Greenhouse Gas Initiative on behalf of a regulatory agency of the State of Maryland, and the development of technical memoranda on various carbon dioxide emissions related topics.

Development of multiple options studies for DOE facilities that address the power supply and transmission system capabilities of potential alternative suppliers for meeting DOE's long-term electrical requirements.

Review of utility procurement strategies and development of electric and natural gas long-term avoided cost projections for several of DOE's national laboratories.

Benchmarking studies of utility operations and maintenance expenses.

As an independent consultant, Mr. Etheridge:

Led an engagement for a western consulting firm to review the load forecasting methodologies and forward price curve models employed by a southwestern municipal water and power utility and to recommend improvements.

Led an engagement for a western consulting firm to develop rate design options for a southwestern municipal water and power utility. The rate design recommendation was designed to facilitate the implementation of operational strategies and the achievement of operational savings identified in a previous consulting engagement. It was also designed to accommodate additional electrical loads if other water municipalities decided to jointly participate in wholesale markets.

Worked with a team from an international consulting firm to support a Midwest utility's effort to ensure that its accounting and rates departments were prepared for the Midwest ISO's "Day 2" market opening scheduled for March 1, 2005. The project involved developing process flows of information required by the accounting and rates departments, and significant interaction with the corporate information technology department. The project also involved reviewing rates and regulatory strategies for potential changes under the Day 2 market rules.

Prepared a competitive analysis for a Midwest utility's unregulated subsidiary on behalf of an international consulting firm. The analysis focused on comparing the subsidiary's product and service offerings, and value propositions, against those of its competitors as well as evaluating the dynamics occurring within the various market segments.

Led an engagement for a western consulting firm to identify strategies for maximizing the savings potential of switching electricity suppliers for a southwestern municipal water and power utility. The economic analyses developed as part of the engagement identified multi-million-dollar savings potential that could be achieved over ten years through changes in both suppliers and operational strategies. In addition, the client realized thousands in immediate savings from billing errors that were identified during the engagement, as well as the potential for hundreds of thousands in annual savings that could be realized through enforcement of the provisions of existing contracts.

Worked with a team from an international consulting firm to facilitate the development of a strategic plan for a western municipal power and water utility. The project included leading the utility's management team through an all-day planning session to develop divisional strategies consistent with the utility's mission statement.

As a strategic director for Sierra Pacific Resources, Mr. Etheridge:

Developed a forecasting model for power and gas prices that was capable of blending fundamentals-based power and gas price forecasts from multiple vendors while maintaining rational market implied heat rates as well as consistent relationships across various gas market centers and power trading hubs in the western U.S. The models enable forecasters to produce timely forecast updates as gas futures prices change or when vendors update their forecasts, while maintaining an easily audited trail of assumptions across forecast updates.

Developed sophisticated financial models to evaluate the ROI potential of distributed generation projects that might be deployed by large commercial and industrial customers. The models investigated gas-fired reciprocating engines and turbines, as well as multi-unit installations, varying performance characteristics and partial standby requirements. This project was undertaken in conjunction with the redesign of retail standby rates and the introduction of new interconnection rules.

Investigated the potential of using private equity partners to pursue power plant development and/or acquisition in southern Nevada, including the possibility of a public/private partnership to leverage the credit ratings of a local governmental entity.

Gained valuable indirect experience in the development and implementation of risk management and risk control procedures while working on energy supply projects when new corporate risk policies were developed, implemented and defended in litigated proceedings.

Supported a telecommunications subsidiary by acting as the lead in the development of business plans for two metro area networks and a long-haul opportunity. Co-presented the business plans with the lead director for the subsidiary to the Board of Directors and obtained the required initial funding of $44 million.

Supported a telecommunications subsidiary by acting as the lead in the development of a fiber-to-the-home business plan with an external team of consultants. The plan addressed the feasibility of multiple bundled service offerings and a targeted deployment in several western markets. Participated in negotiations with subsidiary management and multiple potential partners, including service providers with a national footprint, technology partners and content providers. The plan was tabled when key partnership agreements could not be put in place to pursue a "beta" test of the technology and business model.

Participated on the team that developed a successful bid for a northwest electric utility, including due diligence, management presentations by the company being acquired, and strategy discussions with the CEO and financial advisors.

As leader of the industry restructuring team at Nevada Power Company, Mr. Etheridge:

Reported to the CEO and led an internal team of directors assigned full-time to electric industry restructuring. Directed and managed the team's development and presentation of company positions on restructuring to the Public Utilities Commission of Nevada (PUCN) and to the Nevada Legislature.

Presented expert testimony before the PUCN and the Nevada Legislature. Was responsible for hiring multiple consultants and expert witnesses to facilitate the development of corporate strategy and to support the presentation of positions before the PUCN. In this assignment, represented the company on multiple occasions on television, taped and live radio, in press conferences and interviews, in consumer focus groups, and in presentations to large commercial and industrial customers.

As a member of the CEO's staff, participated in senior management discussions on corporate strategy prior to the merger announcement and throughout the merger integration process, including development of corporate strategy and business line focus for the combined company.

One of only several advisors to the CEO that directly participated with the CEOs from both Nevada Power Company and Sierra Pacific Resources in the final legislative negotiations on the merger and associated restructuring legislation.

In his other assignments at Nevada Power Company, Mr. Etheridge:

Directed a department responsible for rate design studies, marginal cost of service studies, the annualization of sales and revenues for general rate case applications, demand-side pricing, economic and load forecasting, tariff administration, wholesale pricing, and development of supporting testimony in these areas. Built a cohesive, progressive thinking team of experts that was well recognized throughout the company.

Made multiple presentations to executives and groups of large commercial and industrial customers on a variety of industry issues.

Represented the company in negotiations with customers considering alternative sources of supply. Negotiated an 8-year retail power purchase contract with Mirage Resorts, Incorporated to keep them from building a distributed generation project. Regularly briefed the Board of Directors during negotiations and gained Board approval for the final contract. Acted as a spokesperson on television and in the press on this highly publicized contract.

Acted as the lead in the development of economic forecasts, econometric load forecasts, weather normalization of sales and peak demand, short-term sales forecasts and testimony in these areas.

Expert Testimony:

Before the Public Utility Commission of Texas (PUCT), Docket No. 47527 (April 2018), on behalf of DOE. Testimony addressed a billing dispute involving a behind-the-meter wind farm at a federal facility.

Before the Indiana Utility Regulatory Commission (IRUC), Cause No. 44967 (November 2017), on behalf of the Indiana Office of Utility Consumer Counselor (OUCC). Testimony addressed distribution operations and maintenance cost benchmarking.

Before the Maryland Public Service Commission (MPSC), Case No. 9393 (May 2016 and June 2016), on behalf of the Maryland Department of Natural Resources. Testimony addressed a proposed transmission line in eastern Maryland.

Before the IRUC, Cause No. 44688 (January 2016), on behalf of the OUCC. Testimony addressed administrative and general operations and maintenance cost benchmarking and automated meter reading cost savings.

Before the PUCT, Docket No. 43695 (May and June 2015), on behalf of DOE. Testimony addressed operations and maintenance cost benchmarking and rate design issues.

Before the Missouri Public Service Commission, Case No. ER-2012-0174 (August and October 2012), on behalf of the United States Department of Energy (DOE). Testimony addressed off-system sales margins.

Before the PUCT, Docket No. 39896 (March and April 2012), on behalf of DOE. Testimony addressed rate design issues relevant to DOE's Strategic Petroleum Reserve.

Before the Illinois Commerce Commission (ICC), Docket No. 10-0467 (November and December 2010), on behalf of DOE. Testimony addressed proposed distribution loss factors.

Before the Public Utilities Commission of Nevada (PUCN), Docket No. 11-06006 (October 2011), on behalf of DOE. Direct and rebuttal testimony addressed Nevada Power Company's (NPC) proposed class revenue requirement allocation with respect to DOE's Nevada National Security Site (Security Site, formerly the Nevada Test Site) and the U.S. Air Force's Nellis Air Force Base (Nellis AFB).

Before the Wyoming Public Service Commission, Docket No. 20000-384-ER-10 (May 2011), on behalf of DOE. Testimony addressed class cost of service proposals.

Before the Indiana Utility Regulatory Commission (IRUC), Cause No. 38707 FAC87 (March 2011), on behalf of the Indiana Office of Utility Consumer Counselor (OUCC). Testimony provided comments on Duke Energy Indiana's electric hedging policy.

Before the IRUC, Cause No. 43849 (November 2010), on behalf of the OUCC. Testimony provided comments on an electric hedging policy proposed by the Northern Indiana Public Service Company.

Before the ICC, Docket No. 10-0467 (November and December 2010), on behalf of DOE. Testimony addressed proposed distribution loss factors.

Before the MPSC, Case No. 9179 (December 2009), on behalf of the Maryland Department of Natural Resources. Testimony addressed a proposed transmission line in eastern Maryland.

Before the PUCN, Docket No. 08-12002 (April and May 2009), on behalf of DOE. Direct and supplemental testimony addressed NPC's proposed class revenue requirement allocation with respect to DOE's Nevada Test Site (Test Site) and Nellis AFB.

Before the MPSC, Case No. 9165 (March 2009), on behalf of the Maryland Department of Natural Resources. Testimony addressed a proposed and alternative transmission lines in southern Maryland.

Before the PUCN, Docket No. 06-11022 (March 2007), on behalf of DOE. Testimony addressed NPC's proposed class revenue requirement allocation with respect to the Test Site and Nellis AFB.

Before the PUCN in NPC's last deferred energy case before a rate freeze, Docket No. 99-7035, February 2000. Rebuttal testimony addressed the issue of splitting purchased power capacity payments out of deferred energy cases and into general rate cases for cost recovery purposes.

Before the Nevada Legislature, Senate Commerce and Labor Committee, March 1999. Testimony responded to questions on deregulation.

Before the PUCN in NPC's application to provide potentially competitive services as part of industry restructuring, Docket No. 98-12009, June 1999 and December 1998. Testimony addressed steps being taking to establish an arms-length affiliate to provide potentially competitive services.

Before the PUCN in its Investigation of Issues to be Considered as a Result of Restructuring of the Electric Industry (pursuant to Assembly Bill 366), Docket No. 97-8001, September 1997. Testimony addressed NPC's efforts to address restructuring issues and cost unbundling issues.

Before the PUCN in NPC's deferred energy case, Docket No. 97-7030, July 1997. Testimony addressed matching deferred energy rates with rapidly changing deferred energy balances given upward swings in market prices for fuel and purchased energy.

Before the Nevada Legislature, Senate Commerce and Labor Committee, February 1997. Testimony addressed rates during hearings on deregulation.

Before the Public Service Commission of Nevada (PSCN) in a gas utility's filing for approval of a residential gas air conditioning rate schedule, Docket No. 96-10005, February 1997. Testimony on behalf of NPC addressed the potential benefits of pricing strategies that support technological innovation.

Before the PSCN in NPC's deferred energy case and request to move capacity costs into general rates, Docket No. 96-7020, July 1996. Testimony addressed competition, marginal costs, confidentiality issues, and rate design in support of the largest ever-proposed rate reductions for large customers.

Before the PSCN in support of NPC's proposed line extension policies, Docket No. 95-6076, February 1996. Testimony addressed line extension policies in light of competition and marginal costs.

Before the PSCN in a proposed rate schedule in response to DOE's competitive solicitation for the Test Site, Docket No. 95-8038, November 1995 and January 1996. Direct and supplemental testimony addressed a proposal to serve the Test Site under a new partial requirements rate schedule. The case was withdrawn when DOE did not award contracts.

Before the PSCN in NPC's deferred energy case, Docket No. 95-7021, July 1995 and November 1995. Direct testimony and supplemental testimony addressed a request to implement improved cost allocation procedures for calculating base tariff energy rates across rate classes.

Before the PSCN in NPC's application for approval of a negotiated service agreement with Mirage Resorts, Incorporated, Docket No. 95-4061, July 1995. Testimony addressed competition, and the negotiations and cost studies that supported the service agreement.

Before the PSCN in NPC's application for approval of a resource plan, Docket No. 94-7001, February 1995. Testimony addressed load forecasting, competition, long-term avoided costs and econometric modeling.

Before the PSCN in NPC's proposed line extension rules, Docket No. 94-4085, October 1994. Testimony addressed marginal costs relative to line extensions and in total.

Before the PSCN in NPC's application for approval of a resource plan, Docket No. 94-7001, July 1994 and August 1994. Direct and supplemental testimony addressed economic and load forecasting issues.

Before the PSCN in an over-earnings investigation involving NPC, Docket No. 93-11045, June 1994. Direct and supplemental testimony addressed rate design and cost of service.

Before the PSCN in a complaint case brought by a rural cooperative over service to the Test Site, Docket No. 92-9055, January 1994. Testimony addressed the impact of lost sales to the Test Site on remaining retail customers.

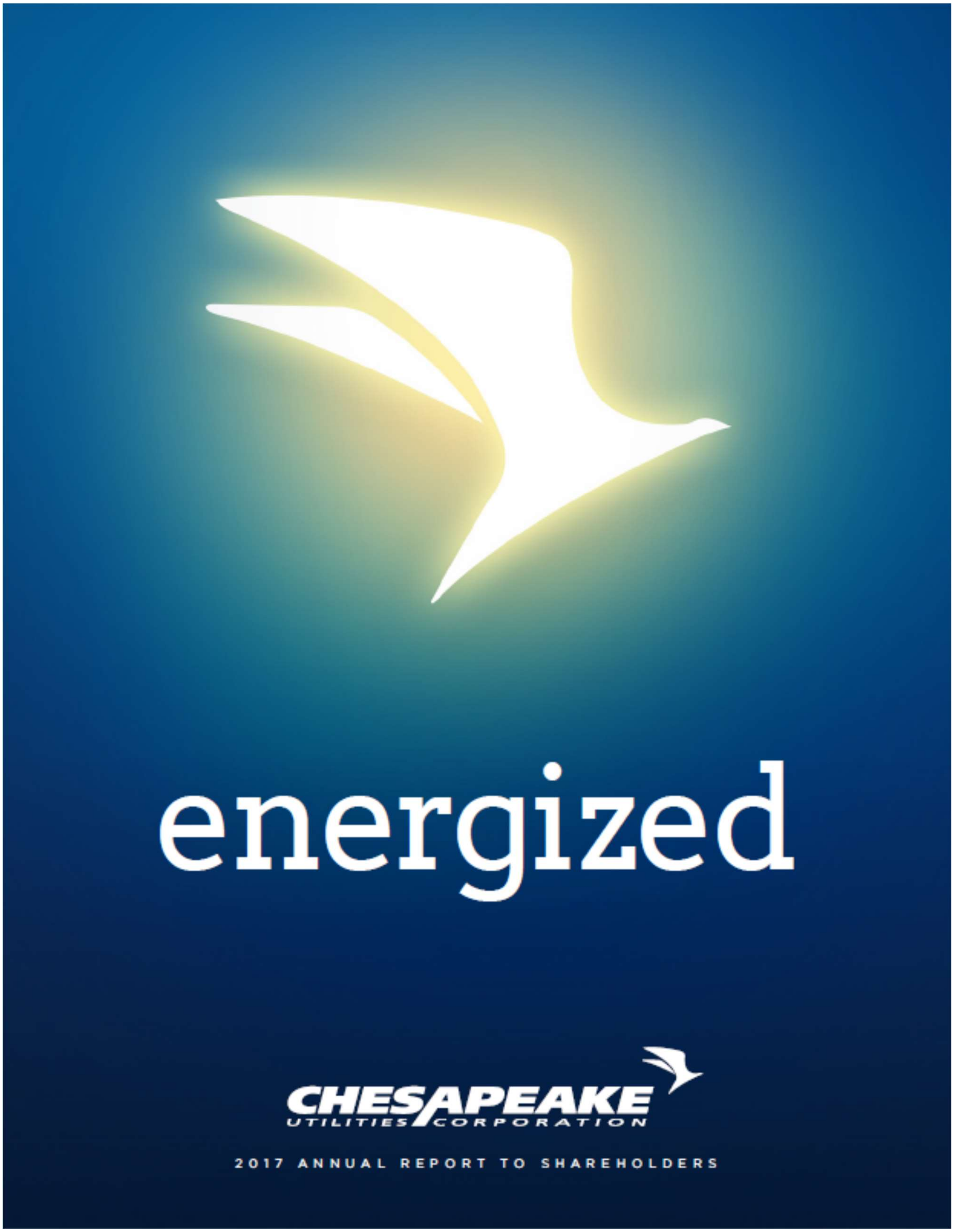
Before the PSCN in NPC's general rate case, Docket No. 92-1067, January 1992. Direct and rebuttal testimony addressed rate design and cost of service.

Before the PSCN in NPC's general rate case, Docket No. 91-5055, May 1991. Testimony addressed rate design and cost of service.

Before the PSCN in NPC's application for approval of a resource plan, Docket No. 88-701, July 1988. Testimony addressed economic and load forecasting.

ATTACHMENT DDE-1

Excerpts from the Company’s 2017 Annual Report to Shareholders


energized
CHESAPEAKE
UTILITIES CORPORATION
2017 ANNUAL REPORT TO SHAREHOLDERS

Driven by our strategy, **energized by our employees**

Our employees are the energy that drives Chesapeake Utilities Corporation.

Their commitment to our customers, communities and each other energizes the Company and helps us achieve sustainable growth. Our employees strive to build meaningful connections that generate opportunities to grow our businesses, develop new markets, and enrich the communities in which we live, work and serve.

The illuminated aspiring and caring bird on the cover of our 2017 Annual Report represents the Company's culture and our aspiring and caring nature that energizes our employees and is a guiding light for our commitment to reach new heights. As we continued to grow this past year, it is evident that our strengths come from our family of businesses moving forward together. We continue to be energized by our growth opportunities identified through our strategic planning process and our powerful growth in 2017.

Highlights of our powerful growth in 2017 include:

- ESNG, our interstate natural gas transmission pipeline company, completed two significant projects – the White Oak Mainline Expansion and System Reliability Projects – and then began construction of a $117 million Expansion Project, the largest in its history. This pipeline expansion will increase firm natural gas pipeline capacity by 25 percent;
- Aspire Energy grew its core business with higher customer growth, added new operating facilities in southern Ohio and expanded its pipeline infrastructure to serve its growing markets throughout the state;
- PESCO realized over 73 percent gross margin growth, primarily from increased natural gas sales and expanded operations into western Pennsylvania with the acquisition of strategically positioned commercial and marketing assets;
- Chesapeake Utilities and FPU increased their customer bases and continued to extend natural gas distribution services on both the Delmarva Peninsula and in Florida. Additionally, Sandpiper Energy increased the energy options available for residents in Ocean City, MD;
- The Eight Flags Combined Heat and Power Plant completed its first year of operations in 2017. It has been recognized with several accolades (discussed further in this report) because of the innovation in its construction and operations;
- Our Florida business unit entered into agreements with Pensacola Energy and other customers in northwest Florida, pursuant to which it will construct a $40 million pipeline that will increase its natural gas service footprint; and
- The Company's propane distribution business experienced significant growth in their retail and wholesale operations. Sharp Energy grew its AutoGas business, which included a new operations and fueling station in Maryland. FPU expanded its propane services by acquiring two small distribution businesses in Florida.

Our employees led the Company to Top Workplace recognition in 2017, marking the sixth consecutive year we received this honor. A third-party survey showed that nine out of 10 Chesapeake employees surveyed said that they would highly recommend working for the Company. Employees highlighted Chesapeake's strong values and ethics; confidence in the direction of the Company; the feeling of being a part of something meaningful; and the genuine appreciation they receive for their efforts.

Our employees are the engines driving our strategic growth. Energized to go the extra mile, our employees deliver safe and outstanding service while identifying innovative solutions that meet the energy needs of our customers and communities, and achieve long-term growth for our Company.

Pictured clockwise from top: Sergio Carrillo, Director, Corporate Development; Amy Snyder, Manager of Origination; and Brian Goff, Manager, Environmental Projects, engage and exchange ideas to help energize our Company.

ATTACHMENT DDE-2

Excerpts from the Company’s Mid-Atlantic Road Show Presentation (March 2018)

CHESAPEAKE UTILITIES CORPORATION

Mid-Atlantic Road Show

Thursday, March 15, 2018

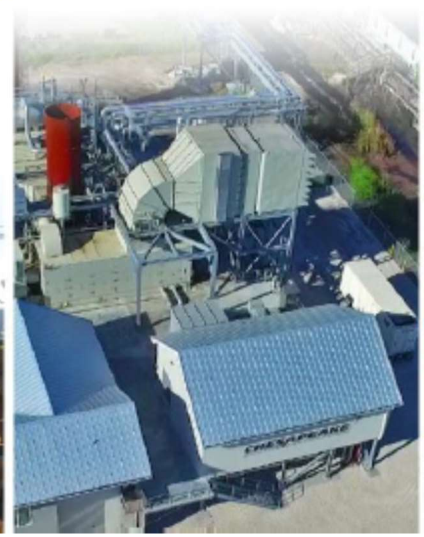
Baltimore, MD and Philadelphia, PA

Engaging Our Team

Investing in Growth

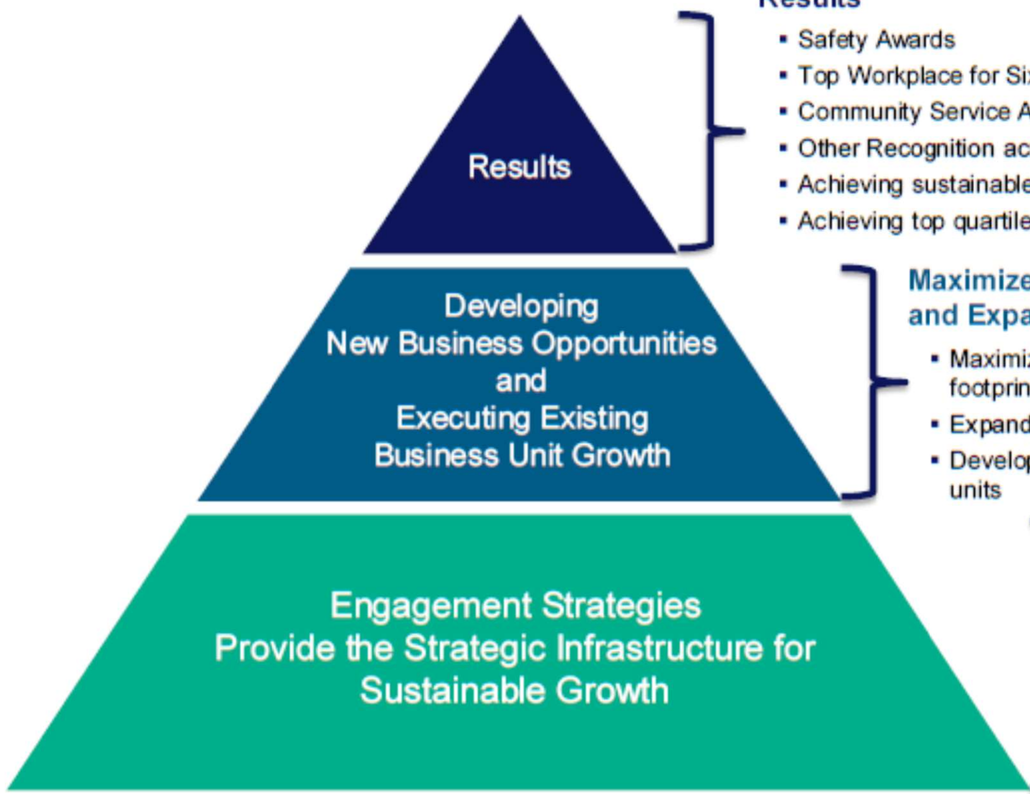
Transforming Opportunities

Reaching New Heights



Proven Approach to Reaching New Heights

Strategic Platform for Sustainable Growth



Results

- Safety Awards
- Top Workplace for Six Years and Top Leadership Awards
- Community Service Awards
- Other Recognition across the Organization
- Achieving sustainable strong growth in earnings
- Achieving top quartile Total Shareholder Return

Maximize Growth in Existing Footprint and Expand Into New Territories

- Maximize organic growth in existing geographic footprint
- Expand into new geographic areas
- Develop additional growth across business units

Engagement Strategies

- Engaged Employees
- Unified Brand Strategy
- Engaging Customers
- Engaging with Communities
- Strategic Thinking

Business Unit Overview

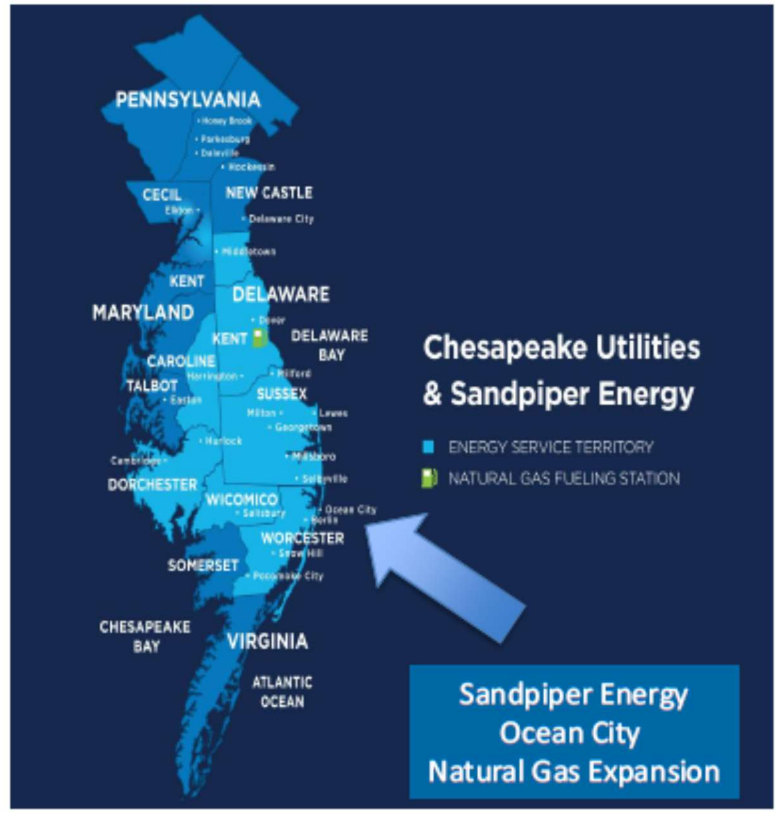
Chesapeake Utilities & Sandpiper Energy

CHESAPEAKE UTILITIES

- **Chesapeake Utilities** distributes natural gas to approximately 65,000 residential and commercial customers in Delaware and Maryland.
- In Delaware, Chesapeake continues to expand its system in southeast Sussex County.
- In Maryland, Chesapeake continues to expand its system in Cecil County.

SANDPIPER ENERGY

- In Maryland, Chesapeake's **Sandpiper Energy** business unit distributes propane and natural gas to approximately 11,000 customers in Worcester County - primarily through community gas systems.
- Sandpiper continues to extend its distribution mains, including providing natural gas service into Ocean City, Maryland.



ATTACHMENT DDE-3

Excerpts from the Company's Annual 10k Filings with the Securities and Exchange Commission

Other Natural Gas Growth - Distribution Operations
Customer growth for the Delmarva Peninsula natural gas distribution operations generated $1.6 million in additional gross margin for the year ended December 31, 2017, compared to the same period in 2016. The average number of residential customers on the Delmarva Peninsula increased by 3.8 percent in 2017 compared to 2016. Our Florida natural gas distribution operations generated $1.2 million in additional gross margin for the year ended December 31, 2017, compared to 2016, with approximately two-thirds of the margin growth generated from commercial and industrial customers and one-third of the margin growth generated from new residential customers. (*See* the Company's 2017 10k, p. 34.)

Other Natural Gas Growth - Distribution Operations
In addition to service expansions, the natural gas distribution operations on the Delmarva Peninsula generated $1.5 million in additional gross margin for 2016, compared to 2015, due to an increase in residential, commercial and industrial customers served. The average number of residential customers on the Delmarva Peninsula increased by 3.6 percent in 2016 compared to 2015. The natural gas distribution operations in Florida generated $1.2 million in additional gross margin in 2016, compared to 2015, due primarily to an increase in commercial and industrial customers in Florida. (*See* the Company's 2016 10k, p. 35.)

Other Natural Gas Growth - Distribution Operations
In addition to service expansions, the natural gas distribution operations on the Delmarva Peninsula generated $1.4 million in additional gross margin for 2015, compared to 2014, due to an increase in residential, commercial and industrial customers served. The number of residential customers on the Delmarva Peninsula increased by 2.7 percent in 2015 compared to 2014. The natural gas distribution operations in Florida generated $1.9 million in additional gross margin for 2015, compared to 2014, due primarily to an increase in commercial and industrial customers in Florida. (*See* the Company's 2015 10k, p. 39.)

Other Natural Gas Growth
In addition to these service expansions, the natural gas distribution operations on the Delmarva Peninsula and in Florida generated $2.8 million of additional gross margin in the year ended December 31, 2014 compared to the same period in 2013, due to increases in the number of residential, commercial and industrial customers served. These increases are due primarily to a three percent increase in residential customers on the Delmarva Peninsula, excluding customers added as a part of the Sandpiper acquisition, and an increase in commercial and industrial customers in Florida. (*See* the Company's 2014 10k, p. 34.)

Investing in Growth
We have continued to expand our resources and capabilities to support growth. Our Delmarva natural gas distribution operation has initiated natural gas distribution expansions in Sussex County, Delaware, and Worcester and Cecil Counties in Maryland, which require the construction and conversion of distribution facilities, as well as the conversion of residential customers' appliances and equipment. To support this growth as well as future expansions, our Delmarva natural gas distribution operation has increased staffing. Resources have also been added in our corporate shared services departments to increase our overall capabilities to support sustained future growth. The additional staffing to support growth increased payroll expenses of our Regulated Energy segment by $2.0 million for the year ended December 31, 2014, compared to 2013. The Company expects to make additional investments in personnel, as needed, to further develop our capability to capitalize on future growth opportunities. (*See* the Company's 2014 10k, pp. 35-36.)

Other Natural Gas Growth
In addition to these service expansions, the natural gas distribution operations on the Delmarva Peninsula and in Florida generated $2.0 million in additional gross margin for the year ended December 31, 2013, due to increases in the number of residential, commercial and industrial customers served. These increases are due primarily to a two-percent increase in residential customers on the Delmarva Peninsula, excluding customers added as a part of the Sandpiper acquisition, and an increase in commercial and industrial customers in Florida. (*See* the Company's 2013 10k, p. 37.)

Investing in Growth
We continue to expand our resources and capabilities to support growth. Our Delmarva natural gas distribution operation is in the early stages of natural gas distribution expansions in Sussex County, Delaware, and Worcester and Cecil Counties, Maryland. These expansions will require not only the construction or conversion of distribution facilities, but also the conversion of residential customers' appliances or equipment. We have begun reorganizing our Delmarva natural gas distribution operation and expect to increase staffing to support future expansions. (*See* the Company's 2013 10k, p. 38.)